A Critique of the Transmission Loss Modelling Methodology as described in "Economic assessment of Transpower's Auckland 400kV grid investment proposal"

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Summary

The loss modelling methodology as described in the Electricity Commission's economic analysis document appears to be valid, and potentially very accurate. However, in some areas the implementation is not consistent with the description in the Commission's report. On the information obtained to date from the Commission's web site and at the public technical briefing held on 18th May, the process as implemented contains sufficient errors and omissions to bring the accuracy of the results into question.

The loss modelling technique as implemented has the following deficiencies:

1. AC system transmission line constraints are not modelled at any stage of the process. This allows the possibility of higher line flows than are possible in reality, and consequently higher losses than would actually occur. The Commission's report states that line constraints are enforced but the data files obtained from their web site indicate that they are not.
2. N-1 transmission contingency constraints are not considered in the SDDP dispatch calculation process (or in the load flow calculations). For some transmission configurations, these constraints are likely to alter the dispatch, fuel costs, losses etc.
3. Cogeneration and geothermal plants have been modelled as being dispatched at their installed capacities, rather than according to the time varying availability data entered into SDDP.
4. The Commission's economic analysis report refers to:
    a. additional reserve generation added to the 220 kV case
    b. the scaling of interconnector impedances by 0.66
    c. addition of a 500 MW generator at Whakamaru.

    None of these features are included in SDDP, and so their effects on losses can not be considered.
5. The grid is modelled only in the region from Bunnythorpe to Henderson in the Commission's AC load flow loss calculations. This approximation may not be valid for situations where constraints occur on the grid within that region. In some constraint situations, changes in dispatch with consequent changes in losses, may occur outside of the region analysed. These changes in losses will not be accounted for.

Commission staff have stated that SDDP can not perform an optimal dispatch of an HVDC link. This is incorrect. The effect on both AC and DC transmission losses of an HVDC link from Whakamaru to Otahuhu could have been modelled explicitly within SDDP.

The calculation approach used, involving a chronological dispatch model along with an AC loadflow, has the potential to accurately calculate line flows. This should give a good representation of power flows over the full range of dispatch situations and consequently accurate loss quantities. Given that a number of approximations are made in the fast decoupled load flow and the large uncertainties in future outcomes, the DC loadflow implemented within SDDP is likely to give reasonable results. The increased accuracy of the complex process used by the Commission may be of limited additional value for this type of analysis.

Loss Calculation Process

The sequence of calculations used by the Commission to calculate losses is as follows:

Repeat for each of the eleven generation scenarios:

- Solve a mid term optimisation case of SDDP, with monthly time steps
- Run the SDDP looper application to carry out the following:
  - Solve a mid term simulation case of SDDP with monthly time steps, and write a water value function for each month of the solution period.
  - For each inflow sequence:
    - For each month of the planning period:
      - Solve a short term optimisation case of SDDP with 168 hourly time steps, writing to a file of hourly injection schedules for each bus, and hourly system marginal prices for each island.
- For each transmission expansion option, and the no expansion option:
  - Solve with the fast decoupled load flow, reading the bus injection file, bus load file and annual system configuration data in PSS/E format, to determine line flows and losses.
  - From line flows, calculate the value of losses using the system marginal price. Store annual cost of losses values for use with the Monte Carlo / NPV model.

The SDDP mid term optimisation takes approximately four hours to solve on Transpower's high specification computers purchased for running SDDP. The model is initiated either manually through the SDDP user interface, or by means of a batching utility for making a series of runs. Some manual processes are needed to prepare data for the detailed scheduling in the next step, although spreadsheet macros are available to assist with this. The SDDP Looper utility solves a mid term simulation followed by a series of short term optimisations without the need for user intervention. The Looper takes approximately three hours to solve per year of the SDDP run, when solving for each of 72 historical inflow outcomes and for the first week of each month of each year. The loadflow model is run as another separate process, requiring its own set of input data files in addition to the bus injections results calculated by the SDDP Looper.

Total annual losses and detailed data by hour, month and flow sequence are available from the MatLab prototype of the loadflow model. The Monte Carlo model requires an annual average cost of losses for each scenario. This is obtained by multiplying the loss value for each hour and flow sequence by the corresponding system marginal price, allowing an annual average cost to be calculated.

Transmission Constraints

The Commission has been queried regarding the treatment of transmission constraints in SDDP. Paragraph 5.4.5 of the Commission's report states "A relatively simple characterisation of the transmission grid is modelled in SDDP; losses on the grid are not represented but thermal constraints are." The control data files used for the short term simulations have the option "monitor selected circuits only" specified. However no circuits have been selected for monitoring, so no AC transmission constraints are actually enforced. Transmission line configuration modification files supplied do not correspond to any of the options specified in the Commission's report.

Capacity of the transmission system is assumed during the loss calculations to be adequate because the large hydro generation scenario was used during the detailed power system analysis carried out by System Studies Group (SSG). This scenario has most new generation south of Auckland. The assumption is made that if the transmission capacity was adequate for this scenario, then it would be adequate for all other scenarios. However, the load flow studies would require some assumptions regarding generation dispatch levels. Therefore it is possible that some dispatch schedules calculated by SDDP would have caused transmission constraints to bind, had these been modelled.

Transmission capacity in SDDP is not constrained to enforce the N-1 transmission constraints. This can be handled by means of “circuit sum” constraints in SDDP, as is done in the SPD model used by the System Operator for electricity market operations. Previous studies have shown that these constraints have far more effect than individual line limits. The absence of the N-1 constraints may be a significant weakness in the dispatch calculation process.

Section 5.1.6 states “the rest of the grid is developed in such a way that all load is met and there are no transmission constraints.” This assumption may be unrealistic, and will affect flows over the lines being studied, and consequently losses.

Loss Valuation

Losses are valued at the appropriate island marginal cost for the corresponding period and inflow sequence. A more appropriate value than the island SRMC might be the marginal price at the receiving end bus. In the event of shortfall at a bus due to line constraints, the losses directly increase shortfall and so should be valued at the shortfall cost.

A spreadsheet supplied by the Commission shows total losses per year for each case, and the total value of losses each year. The SRMC values used are similar to those seen in SDDP, being in the range $56 to $78 per MWh over the period 2005 to 2030 in the spreadsheet. However, section 8.3.75 of the Commission’s economic analysis refers to SRMC being in the range $50/MWh to $55/MWh.

The sensitivity study using LRMC to value losses used a constant figure of $80/MWh, which is hardwired into the MatLab code. Data from the report “Fossil Fuel Electricity Generating Costs”, by East Harbour Management Services for the MED, June 2004, indicate higher values for LRMC under certain assumptions. Analysis of this data gives LRMC values of approximately $109/MWh for the gas scenario and $131/MWh for a coal scenario. These values use the Commission’s 2015 fuel costs, a 7.5% discount rate, 20 year plant life, 60% average plant factor over the life of the plant, and the higher value for capital costs from a sensitivity study. The higher capital costs were used to allow for items not included in the East Harbour estimates.

Hence the Commission’s sensitivity case valuing losses at LRMC under estimates the cost of losses.

Thermal Plant Maintenance Schedules

Certain thermal plants are often modelled as being dispatched according to a fixed pattern, rather than on the basis of system marginal price and the plants’ variable costs. Such plants include geothermal and co-generation plants. Output often follows a similar pattern each year. To represent this feature, the plants are assigned a low variable cost in SDDP and a monthly maintenance schedule is set up. This will result in these plants generally being dispatched up to the capacity available in that specific month.

SDDP has an option to use either average availability data or maintenance schedule data, for all plants modelled. For the average option, installed capacity is derated by the Combined Outage Rate, whereas for the scheduled option, the month by month available capacity is derated by the Forced Outage Rate. The Commission have used the average availability option, but it appears that their intention was to use the scheduled availability option.

The result of this apparent oversight is that cogeneration plants at Southdown and Glenbrook, for example, operate at installed capacity rather than available capacity. This represents a significant increase in generation available in the Auckland area, which will reduce line flows and losses.

220 kV Option

Paragraph 4.2.32 of the Commission's report states that losses are persistently high for the 220kV c. 2017 project, relative to the other projects. Paragraph 6.7.13 states that for this option only, capital charges were included in the analysis to represent additional reserve plant. No explanation is given as to how these capital charges were calculated, what plant they represent, or whether the capital costs have been optimised in some way. It appears that generation from these reserve plants is not considered in the load flow loss modelling.

HVDC Options

One of the five options considered in the Commission's economic analysis is for an HVDC link between Whakamaru and Otahuhu. Other HVDC options were considered in the SSG study. Paragraph 6.7.9 of the Commission's report states that more work would be required to assess the loss benefits of these embedded DC links. At the Technical Briefing held on 18th May, it was stated that SDDP can not carry out optimal HVDC dispatch. Optimal HVDC dispatch can in fact be modelled in SDDP, and the total AC and DC line losses obtained directly from SDDP. A small test modelling the Whakamaru – Otahuhu HVDC option in SDDP has been successfully performed. By calculating an overall optimal dispatch, minimising costs taking into account generation scheduling, AC line flows and the controllable nature of the HVDC lines, SDDP would give an overall optimum solution.

Hypothetical Power System Modifications

Appendix 2 of the Commission's report states that all interconnector impedances are multiplied by 0.66. It goes on to state "It is assumed the system south of WKM is strengthened by a combination of generation and network augmentation. This is modelled by adding a 500 MW generator at WKM." The role of these enhancements is not clear, but neither is included in the SDDP database. As these additional items are not modelled by SDDP, the dispatch and bus injections from SDDP are inconsistent, resulting in the losses calculated by the loadflow also being inconsistent.

Slack Bus Selection

All the SSG studies used Haywards as the system slack bus, whereas the loss calculations load flow used Bunnythorpe. This is reasonable, given that the losses are calculated for the region from Henderson to Bunnythorpe only. However, if Whakamaru had been used as the slack bus, the need for enhanced Whakamaru – Otahuhu transmission capacity would have been increased, i.e. it is possible that selecting Haywards and Bunnythorpe as the slack buses favours delay in expanding capacity, and reduces the additional losses incurred if transmission expansion is delayed. The slack bus issue is also referred to in the review by Karri and Maharaj.

Replication of Commission Studies

The commission initially supplied loadflow input data files for the hydro option only. The SDDP Looper has been run for this case, and similar results obtained. As the SDDP control files used for the Commission's optimisation runs are not available, the small discrepancies observed seem reasonable.

The Matlab load flow and loss model processes the bus injection file calculated by the SDDP Looper. Using the sample file, the output file of total annual losses has been reproduced.

Loss values form an input to the Monte Carlo / NPV model. A spreadsheet of these values has been supplied by the Commission. The MC/NPV model and sensitivity studies using this model (all written in MatLab) have been run successfully.